

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

RESPONSE OF BAY STATE GAS COMPANY TO
RECORD REQUESTS FROM THE D.T.E.
D.T.E. 05-27

Date: July 29, 2005

Responsible: James L. Harrison, Consultant (Cost Studies)

BULK ATTACHMENT

RR-DTE-89: Refer to the Company's response to DTE 2-1. Please provide a complete copy of NERA's landmark publication: "Topic 4, How to Quantify Marginal Cost".

Response: Please see Attachment RR-DTE-89.

HOW TO QUANTIFY MARGINAL COSTS:
TOPIC 4

Prepared by
National Economic Research Associates, Inc.

Prepared for
ELECTRIC UTILITY RATE DESIGN STUDY:
A nationwide effort by the Electric Power Research
Institute, the Edison Electric Institute, the American
Public Power Association, and the National Rural
Electric Cooperative Association for the
National Association of Regulatory Utility Commissioners

March 10, 1977

A nationwide effort by the Electric Power Research Institute, the Edison Electric Institute, the American Public Power Association, and the National Rural Electric Cooperative Association for the National Association of Regulatory Utility Commissioners.

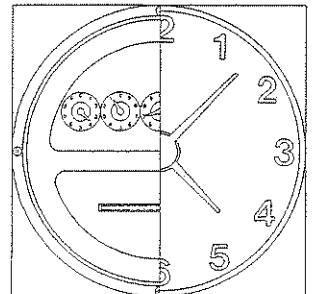
Post Office Box 10412
Palo Alto, California 94303
(415) 493-4800

HOW TO QUANTIFY MARGINAL COSTS:
TOPIC 4

Management Applications
Consulting, Inc.
13740 Research Boulevard
Building U-3
Austin, TX 78750

Prepared by
National Economic Research Associates, Inc.
80 Broad Street
New York, NY 10004

March 10, 1977



This report was prepared by National Economic Research Associates, Inc. It contains information that will be considered by the Project Committee along with other reports, data and information prepared by several other consultants, the various task forces and other participants in the rate design study. This document is not a report of the Project Committee and its publication is for the general information of the industry. The Project Committee will report its findings to the National Association of Regulatory Utility Commissioners in a comprehensive report that will be published in the spring of 1977.

The report of National Economic Research Associates, Inc. (NERA) contains the findings and reflects the views of the consultant. The distribution of the document by the rate design study does not imply an endorsement by the Project Committee or the organizations, utilities or commissions, participating in the rate design study.

National Economic Research Associates, Inc. (NERA) was retained to examine portions of the Plan of Study (e.g., "Costing for Peak Load Pricing," Topic 4). A task force was organized and another consultant (Ebasco Services, Inc.) was engaged to provide additional information on "Costing for Peak Load Pricing." The findings of the task force and Ebasco Services, Inc. will be released concurrently with the NERA report.

Topic 4 is described in the Plan of Study as:

Topic 4 Costing for Peak-Load Pricing

The actual application of the methodology which is to be described in the working paper prepared in Topic 1.3 would require cost data which would be applicable to particular utility systems. A great deal of work with company data drawn from a number of cooperating utilities will be required.

The problem in this area would be, first, to determine what companies would be most useful for inclusion in a detailed cost analysis. The criterion here is not randomness but rather the inclusion of a diversity of problems. A company's willingness to make a great deal of data available is of course the first essential, but thereafter companies should be chosen with a view to covering the major characteristics which are thought to entail different cost structures. These might be summer vs. winter peaking (c.f. Topic 6.1), connection to a power pool, predominance to hydro capacity, etc. Public/private differences may also need to be taken into account. A first topic (4.1) would be to identify the companies willing to participate and those who have usable data, and to make the selection of participating companies, using criteria discussed above.

Topic 4.2 consists of the field work utilizing actual cost data. Using the approach developed in Topic 1.3, company cost studies would be performed. As is clear from work already performed the application of methodology derived from costing theory raises problems of implementation which can require the rethinking of tentative solutions. Moreover, the varying company situations may pose issues not foreseen in the theoretical stage. Consequently, it is essential to the full development of a costing program to engage in this "field work."

A further problem in developing costs is that if a change in rate form is contemplated, demand responses of consumers may change the cost structure. This makes it crucial that the knowledge to be gained about elasticity responses (Topics 2.1 and 2.2), associated with the introduction of different rate structures, be integrated into the costing analysis, to the extent possible, and that sensitivity analyses be performed as to the possible size of cost changes resulting from rate changes. Involved here is the potential of peak shifting (c.f. Topic 6.1) and of revenue erosion.

The results of the first two topics in this section would form the basis of a report (Topic 4.3) which would review the results of cost analyses comparatively to determine what modifications to the theoretical costing analysis are indicated to yield a "de-bugged" methodology.

Finally, (Topic 4.4) while most of the major companies collect cost data for purposes of accounting, budgeting, planning and load management, and some of this will have direct application, there are likely to be definitional inconsistencies and actual gaps in the data, and as work proceeds on earlier phases of the topic, supplementary data collection requirements may become apparent. The completion of Topic 4 should make available a practical costing methodology which could undergird a peak-load pricing approach.

The National Economic Research Associates report is responsive to the requirements of Topic 4. Their findings, as reflected in their report, will be weighed by the Project Committee in reaching its conclusions. Many of the issues in the rate design study are controversial, in some cases data are lacking and in certain instances value judgments are necessary. Thus, readers are cautioned to make their own careful assessment of NERA's work and to consider other sources of information as well. Readers are reminded that some of the materials contained in this report will be an advocates point of view.

NOTICE

This report was prepared by National Economic Research Associates, Inc. (NERA) as an account of work sponsored by the Electric Power Research Institute, Inc. (EPRI). Neither EPRI, members of EPRI, National Economic Research Associates, Inc. nor any person acting on behalf of either: (a) makes any warranty or representation, expressed or implied, with respect to the accuracy, completeness, or usefulness of the information contained in this report, or that the use of any information, apparatus, method, or process disclosed in this report may not infringe privately owned rights; or (b) assumes any liabilities with respect to the use of, or for damages resulting from the use of, any information, apparatus, method, or process disclosed in this report.

ABSTRACT

This report melds economic theory with the practical aspects of electric utility operations and planning. Its purpose is to provide a logical framework for the quantification of the marginal costs of electric utility service. Essentially, the report enables those generally familiar with the industry to understand the basic methodology used to quantify marginal costs and equips those with specific knowledge of demand patterns, operations and planning to develop in-depth time-differentiated marginal cost analyses. The logical framework set out in the report is based upon an understanding of the principles of cost causation. This framework must be adapted to the variegated circumstances applicable to each company and, as the report points out, a proper analysis of marginal costs does not lend itself to a neat, formulistic approach that can be relegated solely to computer.

TABLE OF CONTENTS

	<u>Page</u>
I. SUMMARY	1
II. INTRODUCTION	12
III. DATA SOURCES	20
IV. SELECTING THE COSTING/PRICING TIME PERIODS	25
A. Reconciling Theory with Practicality	27
B. Selecting the Periods--An Example	31
1. Seasonal Periods	31
2. Diurnal Periods	31
V. MARGINAL GENERATING COSTS	34
A. Capacity Costs	34
B. Marginal Energy Costs	42
1. Direct Calculation from Production Cost Modeling Program	44
2. Estimation When Direct Calculation Is Not Feasible	45
3. Operation and Maintenance Expenses	46
4. Grouping and Correcting for Inflation and Trends	47
C. Example of the Computation	48
D. Problems in Application	49
1. Hydro Systems	50
2. System Lambda and Marginal Running Costs	54
3. Short-Run/Long-Run Considerations	56

	<u>Page</u>
VI. MARGINAL TRANSMISSION COSTS	58
A. The Nature of Transmission Investment	58
B. Calculating Marginal Transmission Investment	61
C. Problems in Calculating Marginal Transmission Investment	67
D. Transmission O&M Expenses	69
VII. MARGINAL DISTRIBUTION COSTS	72
A. Marginal Customer-Related Costs--Investment	73
1. The Nature of the Costs	73
2. Making the Computation	75
B. Marginal Demand-Related (Capacity) Costs--Investment	78
1. The Nature of the Costs	78
2. Making the Computation	80
C. Complexities of Distribution Investment	85
D. Distribution O&M Expenses	88
VIII. OTHER COSTS	92
A. Customer Accounts and Sales Expenses	92
B. Administrative and General Expenses	93
IX. COMPUTATION OF CARRYING CHARGES	97
A. The Engineer's Approach	99
B. The Economist's Approach	107
X. MARGINAL LOSSES	117
A. Capacity-Related Losses	118
B. Energy-Related Losses	120

	<u>Page</u>
XI. SUMMARIZING THE COSTS	122
A. Computing Marginal Capacity and Customer Costs	122
B. Allocating Costs to Costing Periods	124
C. Preparing the Summary Table	129

ATTACHMENT A: USE OF LOSS-OF-LOAD PROBABILITIES
TABLES
FIGURES

HOW TO QUANTIFY MARGINAL COSTS

I. SUMMARY

This report provides a framework which will aid the generalist in the understanding of marginal costing methodology and assist the specialist in conducting in-depth time-differentiated marginal cost studies.

Essentially, the report finds that a logical framework can be developed to analyze the three parameters of cost causation: capacity, energy and customers. Additionally, the report provides a method (based on economic theory) of distributing capacity costs over time and of choosing aggregated costing periods that lend themselves to practical translation into rates. This logical framework rests upon an understanding of the principles of cost causation. A brief synopsis of the step-by-step methods for quantifying marginal costs follows.

NOTE: All analyses discussed below should be conducted using constant dollars. This point is emphasized here and, for the sake of economy of words, will be repeated sparingly.

Selecting the Costing/Pricing Time Periods

A. The primary criterion for developing costing periods (with significant differences in marginal costs) is the presence of systematic time-related differences in the probability that load will exceed available capacity. This, combined with

a systematic time-related difference in demand patterns, provides a guide as to the expected periodic shortage (or capacity) costs and, in most cases, the periodic level of the marginal energy costs.

B. A balance must be struck between the precise delineation of time-differentiated marginal costs that, when converted to rates, would bewilder the consumer and an overall averaging of marginal costs over time that would defeat the purpose of time-differentiated pricing. It is recommended that hours of relatively similar costs be grouped together in a fashion that recognizes sensible divisions between the hours of the day, the days of the week and the seasons of the year, and that marginal costs be computed for these costing and ratemaking periods. Consideration of prospective metering capabilities and rate forms can help to refine this process considerably.

C. In recognition of the currently limited knowledge of time-of-use price elasticities, it is recommended that a conservative approach be taken and that peak periods be broadly defined to avoid the risk of peak chasing and to avoid the reversal of the preliminary steps taken in the direction of marginal cost-based rates.

Marginal Generating Capacity Costs

A. The long-run marginal generating capacity cost is the cost of the generating unit that, in an optimal (least

total cost generating mix) system, would be added to accommodate increased peak-period demands. Depending upon the utility's load duration curve and the natural resources available to the utility, this unit will most likely be a combustion turbine, a pumped storage project, a cycling (daily) fossil unit or an additional water wheel at an existing hydro site.

B. The short-run marginal capacity cost will be the shortage cost for hours not served. Theoretically, on an annual basis, if the expected shortage cost equals or exceeds the cost of peaking capacity, system expansion will occur.

C. Due to the fact that capacity is acquired in discrete blocks and long lead times are required, utilities will oscillate around the least total cost expansion curve. Rather than follow the short-run costs in their oscillations around equilibrium, it is recommended that, for marginal costing purposes, the long-run marginal costs of generating capacity be used except in chronic cases of imbalance.

D. In chronic cases of capacity and demand imbalance, such as that occasioned in the Northeast by the sudden rise in oil prices and the need to build baseload nuclear generating units, the capacity cost is either the fixed cost of not retiring older, inefficient units or the cost at which capacity can be bought and sold on contract. This cost can be significantly less than the current cost of peaking capacity. If the situation is expected to last for some time, these marginal capacity costs should be used as the basis for rate-making.

Marginal Energy Costs

A. Marginal energy costs are the fuel and variable operation and maintenance expenses associated with increases in demand. The marginal energy costs can be calculated by examining results from production cost modeling programs to determine what additional cost would be saved or incurred as the result of changes in demand at different points along the load duration curve.

B. All energy produced during each hour should be costed at the marginal energy cost for that hour. Weighted average marginal energy costs for the costing/pricing periods are developed by weighting each marginal energy cost level in the period by the anticipated sales during the time that that particular marginal energy cost level prevails.

C. In the case of systems oscillating around an optimal generating mix equilibrium, it is desirable to analyze marginal energy costs over a full cycle of oscillation, usually five to ten years into the future. In the case of systems chronically out of optimal mix (e.g., the Northeast), it is generally more desirable to reflect the near-term energy costs in rates.

D. In computing marginal energy costs, special consideration must be given to units operating for reasons of area protection, minimum load requirements or steam system requirements. Such units, while oftentimes the most expensive on line, are not marginal energy sources.

E. Impounded hydro energy, when dispatched between combustion turbines and more efficient units, should be costed at the value of displaced energy. When impounded hydro is used as the peaking machine, capacity and energy costs should be developed from construction costs. The floor value of pumped storage energy will be the marginal energy cost of the machine used to pump, adjusted for the pumped storage efficiency factor; otherwise, pumped hydro should be treated the same as pondage.

Transmission Costs

A. Transmission investment is causally related to system peak demand, and a marginal transmission investment per kilowatt of incremental peak demand can be developed.

B. Marginal transmission investment is not necessarily the incremental cost of growth but a level of dollars per kilowatt of system peak demand that will result from the expansion of the transmission system in the most efficient manner consistent with system reliability criteria.

C. Measurement of the level of marginal investment in transmission facilities requires adherence to three basic ground rules. They are:

1. Examine a time period of sufficient length such that lumpiness of investment or temporary aberrations in peak-load growth will not distort the result.

2. Examine both an historic and forecast period so as to illuminate any unusual conditions not related to

marginal costs, as well as to understand the effect of any changes in technology.

3. When developing per-kilowatt investments, unitize total investment on the basis upon which such investment was planned. As a rough rule of thumb, in time periods over which the incremental reserve margin is roughly equal to the long-run planned reserve margin, unitize on the basis of additions to system peak demand. For periods over which the incremental reserve margin is not in line with the long-run planned reserve margin, it may be most appropriate to unitize on the basis of additions to system generating capacity and then adjust upwards for the long-run planned reserve margin.

D. Transmission investment in facilities related solely to remote generator sitings (coal-by-wire) are part of the generation planning trade-off and should not be included as marginal transmission costs.

E. Transmission investment in high voltage interconnections with neighboring utilities or power pools may not be necessary for internal system transmission needs, but may be economically justified because such facilities will make available emergency or diversity capacity that will reduce system reserve requirements. In such a case, the generating capacity costs avoided will exceed the transmission cost incurred. These costs should not be considered as marginal transmission costs, but, rather, should be considered as part of the cost of generation reserve.

F. Analyses of the per-kilowatt operation and maintenance expense on demand-related transmission facilities should be made by examining historic and forecast trends in such expenses in relation to trends in system peak load.

Distribution Costs

A. Investment in an electric distribution system is causally related to three factors: customers, demand and energy. The customer-related portion of the distribution system should be viewed as a system capable of connecting all consumers but providing voltage only and no power. The demand-related portion consists of the components necessary to accommodate the demands that consumers actually place upon the system. The energy-related component refers to the aspect of distribution planning whereby least total costs are achieved by initially placing in service distribution capacity greater than demand and thereby reducing energy losses and replacement costs.

B. The marginal customer-related investment can be determined by computing the cost of reconstructing the system to be able to serve only a minimum demand to each customer and subtracting the material cost of all transformers and conductors. Basically, the remaining cost would consist of construction labor costs and the material costs of poles. A per-customer investment would be determined by dividing the cost of the system by the total number of customers.

C. The preferred method of quantifying marginal demand-related distribution investment is a statistical approach regressing investment in demand-related distribution accounts against distribution system peak demands. This method can be used only over a time period of sufficient length (for purposes of statistical validity) in which distribution technology and planning criteria were not abruptly changed.

D. An alternate method, similar to the method of calculating marginal transmission investment per kilowatt, can be used (after subtracting customer-related investments) if there are problems in applying the statistical approach. In any case, expenditures not related to increased demand, such as expenditures for the replacement of retirements or road widenings, must not be included when calculating marginal demand-related distribution investment.

E. Operation and maintenance expenses incurred on the distribution system related to the existence of customers and demand should be analyzed and unit marginal costs developed. Methods of accomplishing these analyses are outlined in the report.

F. Distribution costs should be adjusted to reflect differing class load characteristics and the voltage level at which power is delivered.

Other Marginal Costs

Marginal cost aspects of customer accounts, sales, and administrative and general expenses should be analyzed and

included in the total marginal cost picture. Customer accounts and sales expenses lend themselves to a dollars-per-customer computation. Administrative and general expenses are included in all other expenses to which they are applicable.

Carrying Charges

A. The total present value of all fixed costs associated with a long-run unit investment in a given function should be analyzed. The basis for this analysis is the revenue requirements method used by engineering economists.

B. From the total present value of the costs associated with the investment, the appropriate first year charge should be estimated. If no change in the price of replacement equipment is projected (if inflation is expected to be offset by technical progress), this can be done by estimating a levelized annual carrying charge using the tax life (asset depreciation guideline range lower limit) of the project.

C. If technical progress is expected, the cost of the equipment is raised because, by buying this year rather than next, a certain price reduction is foregone. By parallel reasoning, if inflation is expected, the cost is reduced. Buying the machine this year rather than next has saved the higher price which will be demanded next year.

Marginal Losses

A. Loss factors are used to convert costs measured at system level to costs measured at the meter and thus provide for an easier translation of costs into rates.

B. All marginal capacity or demand costs should be adjusted by electric losses at time of system peak demand.

C. All marginal energy costs should be adjusted by periodic marginal energy losses.

Summarizing the Costs

A. Capacity costs for each class for the generation and transmission functions should be annualized (using the percentage carrying charges) and summed. Annualized distribution costs may be added to this sum depending upon ratemaking considerations. Demand-related operation and maintenance expenses for each function should be added to this total. Class cost differentials will exist due to distribution capacity cost differentials arising from different class load characteristics and voltage delivery levels.

B. The resulting marginal capacity costs should be allocated to costing/pricing periods on the basis of the relative risk of load exceeding capacity in each period and the number of hours of risk in each period.

C. The resulting periodic capacity costs are still expressed in terms of dollars per kilowatt of system peak demand. They should be adjusted to dollars per kilowatt of periodic mean peak demand by dividing the cost by the ratio between periodic mean peak demand and system peak demand. Consultation should be held with the ratemaker to determine the most convenient method of expressing the costs.

D. Customer costs should be annualized using the percentage carrying charge figure; customer-related distribution expenses and customer accounts and sales expenses should be added to the annual customer cost.

E. The periodic marginal energy costs adjusted for losses are already in a form suitable for use by the rate-maker.

F. The annual cost per customer, the capacity cost per kilowatt of mean peak demand and the periodic energy cost should be summarized for each costing/pricing period and presented to the ratemaker as the bases upon which to formulate rate structure.

II. INTRODUCTION

The purpose of this report is to outline an appropriate way in which to go about quantifying the marginal costs of supplying electric utility service. The object of the costing process outlined herein is to quantify the marginal costs of a utility, not the revenue requirements of a utility. Translation of these costs into rates is not addressed herein although it will be necessary, at times, to speak of costs as though they were rates.

The scope of an analysis of cost causation for purposes of time-differentiated pricing attacks issues broader in scope than those covered in cost studies for ratemaking previously undertaken in the electric utility industry. The sought-after concept is time-related, forward-looking and marginalist in nature. This cost analysis must make available to the ratemaker costs related to time of day, season of the year and weather (to name the most obvious), so that ratemaking decisions may be made. One must also keep in mind the current state of the metering art and current administrative feasibility. Further, and perhaps most importantly, these costs should point the way to desirable changes in metering and administration of rates as targets to be achieved.

We wish to point out that such a cost analysis does not lend itself to a neat, formulistic approach that can be

relegated to a computer using the books and records of the company as sources of input. Rather, this cost analysis requires an understanding of cost causation and of the inter-relationships between the varying cost elements, as well as the ability to interpret an array of data that ranges from the utility's books of account to the effects of changing fuel costs on system dispatch. The key to the analysis lies in an understanding of the processes by which the various components of an electric system are planned. Without knowledge of these processes, the costs found in the books of account will remain mute as to what caused them to be incurred. Therefore, we will, in the various segments of this report, discuss the problems that will be encountered in the practical application of the theory as set forth in Topic 1.3, offer solutions to the more common problems encountered, and provide sample computations.

The marginal cost of supplying electric service can be separated into three categories. The first, marginal customer cost, is the cost associated with building and having in place an electric system that provides area coverage and "hook-up" for a population of minimum demand customers. The second, marginal demand cost, is the cost associated with building and maintaining a system with sufficient capacity to meet incremental electrical demands. The third, marginal energy cost, is the cost of producing the power that is demanded. Each of these costs is computed in terms of current

or "real" dollars and thus they do not reflect any general inflationary expectations. This is done in order that these costs might reflect today's costs of providing electric service. In this way, the consumers, in their decision-making processes, will be choosing between electricity and some other good or service on the basis of costs stated in current dollars

What are the characteristics of these costs?

Turning first to capacity- or demand-related costs, we find that they tend to be lumpy. Scale economies and construction lead times combined dictate the installation of large discrete lumps of capacity. These large lumps of capacity both relieve loads on older, less efficient units (in the case of generation) and allow room for additional growth on the system. Taking our lead from Boiteux,¹ we have treated these lumpy additions as though they were more flexible and could be had in very small increments of capacity. To do so, we derive unit costs of generation based on the unit cost of capacity. In the case of transmission and distribution, we utilize the stream of investments related to load to derive a unit capacity cost. All of these unit costs are expressed in current dollars, and they represent today's cost of adding a small increment of load to an electric utility system.

With respect to marginal energy costs, it is also necessary to examine costs over a period of years. The

¹ Marcel Boiteux, "Peak-Load Pricing," The Journal of Business, April 1960, p. 176.

appropriate measure of marginal energy costs is an average of marginal costs over the period examined. The reason is that system optimality cannot be thought of as a point occurrence as long as there is growth. Here, again, it is the combination of scale economies and construction lead times that makes it necessary to get at the appropriate measure of long-run marginal cost in a somewhat roundabout manner. Let us look at a simple example to illustrate the point. In a growing, thermally dominated generation system, peaking units will be added first, followed by a baseload unit. During the construction of the baseload plant, the peaking units will be required to run a longer number of hours than indicated as optimal by the economic trade-offs between these two types of plant. When the baseload unit comes on line, the peaking units will run less than the optimal number of hours. Over the period of a planning cycle, the peaking unit will, on average, operate the optimal number of hours.

The long-run marginal demand and energy costs of an electric utility vary with the time of consumption. The marginal cost of energy at a given time is the marginal fuel and variable operation and maintenance expenses that will result from an increment in demand at that time. In other words, for each hour of the year the plants available for use are arranged in ascending order of operating costs; the dispatch plan is usually to add operating units in ascending order of running costs as demand increases; and, therefore,

the marginal cost curve for each hour is the relationship between kilowatt demand and the running costs per kilowatt-hour

This marginal cost curve (as a function of demand) can be thought of as rising, with running costs, until the point at which capacity is exceeded, where the cost becomes the shortage cost and the curve rises very sharply. The shortage cost corresponds to the costs incurred by customers who would not be served in the event of demand exceeding capacity. These costs could, in principle, be calculated directly. The French nationalized electric industry does just that; it looks at its plan for load shedding and calculates the loss of value added for industries which it would shed in a situation of potential power failure. It then plans to add capacity to the point at which the cost of the last unit of capacity added equals the probable cost of a failure. In the United States, however, we set our capacity requirements (including reserves) with reference to a set of reliability criteria. For purposes of what follows, we will assume that these criteria, while set subjectively, adequately reflect the shortage costs or the costs of not having enough. This means that the system has been planned to equalize the cost of failure with the cost of the last unit of capacity; the shortage costs can then be determined, as it were, in reverse, by reference to the capital cost of the last unit of capacity. This "last unit" of capacity is the unit which the company customarily would use to meet the peak (i.e., loads of shortest duration).

This shortage cost, or marginal capacity cost, cannot simply be charged to the peak hour. Rather, the cost must be assigned, in principle, to each hour based on the relative probability that load will exceed capacity in that hour. We say this because (in principle) the reliability criterion commonly used is the sum of the probabilities for each hour that the load will not be met. Simply put, during some hours there is a greater risk that capacity will be exceeded than in others. Thus, it is logical, in principle, to assign a portion of the responsibility for the cost of the "last unit" of capacity to each hour in proportion to the degree of risk that capacity will be exceeded.² However, as will be seen later in this report,³ it is not necessary as a practical matter to make this computation for every hour of the year.

It is important to recognize that these marginal costs do not represent a form of prospective rate base or average incremental costs, but reflect the time-differentiated marginal costs upon which consumption decisions should be based. These costs do represent the cost of reproducing the service provided at today's costs and under today's technologies, and are the costs that, in the long run (as defined by the economist) will be saved or incurred in the production and delivery of electric energy. Many people have incorrectly come

² See Topic 1.3, pages 57 to 58 and 77 to 81 (refers to NERA's report on Topic 1.3).

³ See pages 27 to 30 below.

to view marginal cost as the cost of growth. Economically speaking, this view is wrong because in the long run it will be necessary, even without peak-load growth, to replace old and unreliable facilities at current costs and with current technology. Thus, in the long run, a decision to consume less electricity (as opposed to a decision to continue to consume) will reduce the costs incurred in that replacement.

All costs computed for the purposes of this presentation are on the basis of prices currently prevailing. By this it is meant that general inflation must be excluded from estimates of costs during the period studied, but relative changes in costs (for example, between different primary energy sources) which could affect the choice of equipment must be taken into consideration. As further inflation takes place, the cost estimates developed will have to be adjusted.⁴

In deriving marginal costs, it may be necessary to examine a utility's costs both prospectively and retrospectively. Additions to plant tend to be lumpy and, in some cases, economics dictates the installation of a facility in advance of the load to be met by that facility. In this event, the load and the investment must be brought into phase with one another if proper unit costs are to be derived.

⁴ While anticipated inflation is removed from the cost estimates utilized herein the effects of inflation must be taken into account. See Section IX for a discussion of how this is accomplished.

There are investments incurred to replace aging plant, to move facilities at the request of a governmental agency and to improve service reliability.⁵ None of these investments is related to increments in load or customers and, therefore, they should not enter the marginal cost analysis. However, while these kinds of expenditures should not be related to load increments, the depreciation allowance included in the annual carrying cost of those facilities which are related to load increments should reflect the probability that similar circumstances will arise in the future.

We have been asked if there is a specific time period to be used in the analysis of a utility's marginal costs. The answer is no. Nor is there any logical rationale that demands that the same time period be used in the analysis of each of the components of marginal costs. All that is required in deriving long-run marginal costs is that the time frame be sufficiently long so that the costs fully reflect the reoptimization of the system. Since the distribution system is continually being optimized, a relatively short period of time will generally provide sufficient information to derive long-run marginal costs. Generation and transmission, however, may require analysis over a longer period of time since those segments of the system may take many years to reoptimize.

⁵ We speak here of "catch-up" expenditure. It is assumed that expenditures to meet load additions include the costs of providing a level of reliability.

III. DATA SOURCES

Proper quantification of marginal costs requires substantial amounts of information regarding the cost and operating characteristics of the company under study. Peak-load forecasts, budgeted capital and operation and maintenance expenses, forecast fuel expense and forecast system dispatch are examples of the type of information necessary to compute marginal cost levels. Loss-of-load probabilities and daily load curves are information that is essential in choosing costing periods. Electric losses at time of peak and under different load conditions are necessary to adjust demand costs to allow for losses at time of peak and to adjust energy costs to allow for incremental energy losses.

The primary sources for information of this type are the people who are constantly involved in the planning and operation of the electric system. Since marginal costs look forward rather than backward, planning and operating personnel are in a position to generate the kinds of information necessary for the costing process. The following kinds of information are necessary to complete a marginal cost study.

1. a. Summer and winter peak-load forecasts for the next 10 years;

- b. actual and weather-normalized summer and winter peak loads for the past 10 years; and

- c. monthly cooling and heating degree days for the last 10 years and weather conditions on the summer and winter peak days for the last 10 years.

In this regard, we need to know the relationship between weather for the period and "normal" weather. (A write-up explaining peak-normalization procedures, including design-day conditions, would be helpful.)

2. Hourly system loads for the past 10 years, in computer-compatible form, which are used to develop daily load curves. (A copy of the computer data submitted to EEI* is usually the most readily available.)

3. Hourly marginal energy costs (including variable operation and maintenance expense) for the next five to 10 years in computer-compatible form. If these are not available, the following data will generally provide sufficient information to compute marginal energy costs. (These data should also be in computer-compatible form for ease of handling.)

a. a month-by-month system dispatch showing the amount of hours each unit will be run;

b. the energy generated by each plant;

c. the MBtu consumed by each plant;

d. the cost of fuel per MBtu in base-year dollars (general inflation excluded);

e. the base-year dollar cost per kilowatt-hour of variable operation and maintenance expenses by plant; and

f. a description of any operating conditions that significantly alter dispatch from being done on a "merit order" basis.

* EEI: Edison Electric Institute.

4. Monthly load duration curves expected to be typical of the planning period.

5. Loss-of-load probabilities for each hour for the next five to 10 years. If these are not available, loss-of-load probabilities by month for day (peak) and night (off-peak) for the next five to 10 years.

6. Planned production capacity additions for the next five to 10 years and the timing of these units. Also, the results of any long-range generation optimum mix studies.

7. The planned capacity reserve margin over the next five to 10 years. The method of generation planning employed, e.g., yearly loss-of-load probability.

8. Long-range, five-to-10 year budgeted annual expenditures for transmission investment in present-day dollars, indicating, if possible, any dollars budgeted for replacement of retired plant and any unusual projects taking place during the period.

9. Long-range, five-to-10 year budgeted annual expenditures for distribution investment in present-day dollars, indicating, if possible, dollars budgeted for replacement and/or reliability.

10. A tabulation of capital expenditures over the last 20 years related to distribution plant broken down by subaccount and by voltage level. Also, a tabulation of any significant unusual expenditures during this period, such as those related to major nonrecurring projects.

11. The cost of a minimum demand distribution system as outlined in Section VII-A.

12. For the last 20 years, an analysis of the contribution to peak by customers by class and voltage level. Also, the average and year-end number of customers by customer class, served from each voltage level.

13. The capital structure that will be used to finance projects undertaken during the planning period. The cost of capital faced during the planning period. A description of any accounting practices related to computing revenue requirements for ratemaking purposes (i.e., use of reserves for rate stabilization, etc.).

14. The type of Iowa survivor curve that will be used to estimate the dispersion pattern of the types of planned investments. The service life that will be used for straight-line depreciation of planned investment, by type of investment (i.e., transmission, distribution and generation by type of fuel). If these data are unavailable for planned investments, supply information on the type of curve currently used and the corresponding service life, by type of investment.

15. A detailed description of what comprises the rate base.

16. A description of all taxes, or payments in lieu of taxes, paid to the federal, state or local governments.

17. A description of any specific load research work that has been performed.

18. An analysis of losses by voltage level for demand and energy.

19. A map of the system showing existing and proposed generator sites and transmission lines.

20. Copies of the company's FPC* Form 1 for at least the last five years.

21. Copies of the company's Uniform Statistical Report for at least the last five years.

It is recognized that all of these data are not kept in a usable form by all utilities. In those cases where this is true, sufficient data can usually be found to enable the computation of reasonably precise estimates of marginal costs that will clearly point out the direction in which costs are moving. The existence of less than complete data should not bar the estimation of marginal costs--it is better to move in the proper direction than not to move at all.

* FPC: Federal Power Commission.

IV. SELECTING THE COSTING/PRICING TIME PERIODS

Our objective in establishing costing/pricing periods is to simultaneously recognize major differences in marginal cost over the load cycle and practical limitations on the number of periods for which rates can be set.

Variations in marginal costs over the load cycle arise from two sources. First, there are variations in the expected marginal capacity (or shortage) costs and, second, there are variations in the marginal energy costs. Generally, the expected marginal capacity costs and the marginal energy costs will vary with one another over the load cycle. Similarly, these costs will tend to vary directly with the probability that demand will exceed available capacity during any particular period. Therefore, probability that load will exceed capacity becomes a primary criterion for developing costing/pricing periods with significant differences in marginal cost.

The logic of this approach becomes clearer if we consider the causal characteristics of marginal capacity costs. The marginal cost of capacity and reserve cannot simply be charged to the peak hour. Rather, as we have explained in our introduction, the cost must be assigned, in principle, to each hour based on the relative probability that load will exceed capacity in that hour. We say this because the various planning criteria relating to reliability of supply take into account the need for adequate capacity at all hours. While the hour of peak demand is generally the hour of greatest

exposure to outage, other hours do bear a risk--although usually of a lesser magnitude. Simply put, during some hours there is a greater risk that capacity will be exceeded than in others. Thus, it is logical in principle, to assign a portion of the responsibility for the cost of the "last unit" of capacity and reserve to each hour in proportion to the degree of risk that capacity will be exceeded.⁶

These probabilities are a consequence of the planning process and can be computed even if a utility does not use a probabilistic criterion for production capacity planning.

Those utilities which do use probabilistic methods employ a variety of computational approaches (e.g., loss-of-load probability, megawatt-days of shortage, loss-of-energy probability) that embody the basic concept in a manner suitable for use in a time-differentiated marginal cost study. In terms of the conceptual background developed in earlier sections of this report, the use of such probabilities is the theoretically correct basis for the determination of relatively homogeneous costing/pricing periods.

In what follows, we will discuss the interaction of the theoretical and practical aspects of selecting costing/pricing periods and provide an example of how to select the periods.⁷

⁶ See Attachment A for an exposition of the logic involved in this methodology. See also Topic 1.3, pages 57 to 58 and 77 to 81.

⁷ Attachment A sets forth a simplified means of computing loss-of-load probabilities.

A. Reconciling Theory with Practicality

In order to select costing/pricing periods, ideally one would want to know for each hour of the year the absolute probability that load would exceed electric production capacity in that hour. The probability sought here must take into account maintenance, equipment deratings, the probability of forced outage and the probability of load variation about the forecasted value. Since most utilities are either part of a power pool or have interconnections with other utilities, the effects of such arrangements must be taken into account. It is quite likely that the appropriate probability will be that of the pool rather than that of the individual utility.

In some pooling arrangements, however, planning criteria are a mixture of physical and legal requirements, as, for example, when each member is required to maintain a fixed reserve over and above its own peak regardless of the time of occurrence. The pool requirements may be based on a more comprehensive analysis, but each individual utility will add capacity based only on its own peak. In this case, and in the case of a utility contracting with someone else for its total capacity requirements, the relevant probability for purposes of assessing capacity responsibility becomes the probability that any individual hour will in fact be the peak hour, which is not the same⁸ as the probability that load will exceed available

⁸ While peak-hour probability is conceptually different from the probability that load will exceed capacity, electric systems with strong seasonal peaking characteristics will tend to have similar patterns of loss-of-load probabilities and peak-hour probabilities.

capacity for each hour. In these circumstances, individual appraisals of the company's relation to the pool and the flexibility of the rules have to be made.⁹

It has been suggested that one could simply measure the relative size of available reserve capacity in each hour and allocate capacity costs to periods on that basis. While such an approach has a certain appeal, based on simplicity and ease of computation, it does not comport with the planning process which serves as the basis for the costing methodology proposed in this report. To cite a simple example, when the planner forecasts energy output, he will always include an allowance for the possibility that a machine will be forced out of service, whereas the measure of relative reserve would ignore the probability that the total reserve might not be able to function (e.g., a combustion turbine expected to start automatically may not do so). We would take this approach with great trepidation and only as a last resort.

In the traditional, nontime-differentiated approach to costing for ratemaking purposes, there is a very clear separation between costing and ratemaking. Theoretically speaking, it is possible to maintain the same very clear separation between these two elements when computing time-differentiated marginal costs. Pragmatically, however, it

⁹ While we will recognize the cost-causative effects of existing pooling arrangements because ignoring them could lead to distortion, we feel that economically efficient pooling arrangements should allow the use of the ideal concept expressed on page 27.

makes little sense to compute a cost for each hour of the year when one clearly would not attempt to price every hour of the year. Therefore, we recommend that hours of relatively similar costs be grouped together in a fashion that recognizes sensible divisions between the hours of the day, days of the week and seasons of the year, and that marginal costs be computed for these costing and ratemaking periods.

Thus, while it is of paramount importance that the consumer be informed of the cost of the decision to consume at any given time (hence the move towards time-differentiated marginal cost pricing), a balance must be struck between a precise delineation of time-differentiated costs that would leave the consumer totally bewildered and an overall averaging of marginal cost prices over time that would defeat the purpose of using marginal cost price signals. In other words, one faces a cost-benefit trade-off between consumer confusion and economic efficiency.

In the course of evaluating this trade-off, consideration must also be given to the fact that currently very little is known about peak-period price elasticities. If such elasticities were known, one could predict shifts in the patterns of electricity consumption and compute the time-differentiated marginal costs associated with the new patterns of use. This is an iterative process that seeks an equilibrium between demand at any time and the cost of supplying electricity at that time.

However, since measurements of peak-period elasticities are not currently available, the iterative process must occur over time as the application of marginal cost pricing develops.¹⁰ As a starting point, we recommend a conservative approach and propose to define the diurnal peak period in a relatively broad manner in order to avoid the risk of "peak chasing" until more is known about peak-period elasticities. In this way movement towards the use of marginal costs as rates can begin without precise knowledge of peak-period elasticities and with a very low probability that any first steps will have to be reversed.

The foregoing does not mean, however, that one cannot evaluate the risk of pricing a more narrowly defined peak. A qualitative approach to this evaluation would be to compute the elasticity required to cause a one- or two-hour load shift¹¹ were the more narrowly defined peak used as a costing/pricing period. If an extremely small elasticity could cause significant load shifting, caution is indicated. Conversely, if a relatively large elasticity would be required to produce significant load shifting, one may wish to separately cost the more narrowly defined peak.

¹⁰ See Topic 1.3, pages 45 to 48.

¹¹ For example, consider a utility having peaks during the hours 11:00 a.m.-1:00 p.m. and 2:00 p.m.-4:00 p.m. with a deep trough in its load curve between 1:00 p.m. and 2:00 p.m. If use during the hour between 1:00 p.m. and 2:00 p.m. were to be charged a very low price, a shift in lunch hours could cause such a load shift.

B. Selecting the Periods--An Example

1. Seasonal Periods

Ideally, the periods selected, should contain components of relatively homogeneous cost characteristics, but should also make sense to the consumer. In other words, we must make a judgment as to the cost-benefit trade-off between economic efficiency and consumer confusion. The loss-of-load probabilities (LOLPs) shown in Column (1) of Table 1 are illustrative of the monthly LOLPs that would be computed by a system planner. It can be seen that those grouped into the winter period (October to March) are, with a single exception (January), greater than one. Since January is in the middle of the home heating season, it does not make sense to propose that it be priced differently than the rest of that season. Those months grouped into the base running period (April to September) are relatively homogeneous and show no aberrations requiring investigation. In this case, the selection of seasonal costing/pricing periods can be accomplished by inspection.

Table 1 also shows the calculation of the relative mean LOLP in each period. It is the pertinent relative mean LOLP in each period that is used to allocate the capacity costs of each of the segments of the system between periods.¹²

2. Diurnal Periods

An inspection of the illustrative daily load curves (Figure 1) shows that on Saturdays and Sundays the maximum

¹² See discussion in Attachment A.

anticipated demand is only 65 percent of that anticipated on the typical weekday. The only likely result of additional demands on the weekend is an increase in the running cost. If such an increase did occur, the running costs would be adjusted. Since, due to the low load level, an increase in load would not substantially raise the weekend probability of shortage in relation to the weekdays, the weekend is considered to be part of the off-peak hour period. Similar logic applies to weekday late night and early morning loads which are low in relation to other daily loads.

Since we have no precise knowledge of elasticities, the selection of when load is sufficiently high to indicate the beginning of a peak period is largely judgmental. Intuitively, one recognizes that the high costs of changing habits and social patterns will prohibit large shifts in load to the weekend and night hours. In analyzing hours during the standard five-day workweek, however, greater caution is indicated.

The average daily load curve for the winter period (Figure 2) we are examining is roughly 70 percent of daily peak through the hour ending 5:00 a.m. At 6:00 a.m., it rises to 80 percent and to 90 percent at 7:00 a.m. The daily peak for both the average and peak day occurs at 9:00 a.m. A knowledge of the cost of heating and heat loss rates in residences leads us to conclude that the peak period should begin at

7:00 a.m. or a new peak will be created. Discussions with operating personnel, however, indicate that if the period begins at 7:00 a.m. and the result is that consumers will in response start more heating at 6:00 a.m., the rate of rise in load between 5:00 a.m. and 6:00 a.m. will be too steep. As a result, additional costs may be incurred to enable the system to accept load at a greater rate. In this case, we would begin the peak period at 6:00 a.m. The load will stay at or above 90 percent of peak through the hour ending 9:00 p.m. By 10:00 p.m., it drops to 85 percent and by 11:00 p.m. to 80 percent. In this case, we would hesitate to end the peak period before 9:00 p.m. but would not extend it to the hour ending 10:00 p.m. We say this because at 9:00 p.m., the load is beginning to taper off and the chance of establishing a new peak is diminishing. While social patterns will inhibit large load shifts, the area from 9:00 p.m. on will provide an opportunity for customers to consume at off-peak rates. If there were to be a significant dip in load during the day, we would, perhaps, designate a third period which would be assigned a cost somewhere between that of the peak and off-peak periods.

Using the same principles as above, we choose a diurnal period for the base season.

V. MARGINAL GENERATING COSTS

A. Capacity Costs

An electric utility must construct sufficient generating capacity to meet its demand over the year. This capacity will usually include a mix of baseload, intermediate and peaking plants. The system is not constructed to serve only the peak. In fact, the generation mix and the resulting capital costs of a system constructed to serve only the peak would be quite different from a system constructed to serve load patterns that utilities commonly face.

The determination of the marginal cost of generating capacity requires an understanding of the planning process. Simply put, the planner attempts to meet the loads depicted by the load duration curve by choosing, from all plans capable of supplying the anticipated loads, the least possible cost plan. The least possible cost plan is the plan that yields the lowest present worth of all costs to be incurred over the life of the equipment to be used in carrying out the plan. To accomplish this, the planner must choose from an array of possible plants which vary in initial cost, expected life and running costs per kilowatt-hour.

How does the planner choose the best plan? He does so by means of a series of economic trade-offs between the operating and capital cost characteristics of the available

kinds of capacity and the requirements of the load duration curve.¹³

For each possible plant, there is a series of total costs per kilowatt which rises according to the number of hours the plant is used. As the number of hours of use increases, there comes a point at which additional operation of this machine will result in a higher total cost than if some other machine were to be used. Let us consider that there are three kinds of equipment available:

1. Peaking units having low capital costs and high running costs;
2. Cycling units having medium capital costs and medium running costs; and
3. Baseload units having high capital costs and low running costs.

The planner attempts to "fill" the area under the load duration curve in the following notional way in order to minimize total cost:

1. Select an amount of baseload capacity such that the minimum number of hours any unit of baseload capacity runs is the number of hours at which the total cost of a unit of baseload capacity is less than or equal to that of a cycling unit.

¹³ See Topic 1.3, pages 51 to 58 and Attachment A (of Topic 1.3) for a discussion of these procedures in the context of a simplified model.

2. Use an amount of cycling capacity defined in a similar manner.

3. Fill the remaining area with peaking units. Additionally, if the planner was asked how he would meet an additional increment of load during the peak period, his answer always would be to use a peaking unit (or some equivalent low capital cost alternative).

This is clearly inconsistent with the more traditional view that the cost of capacity at the peak (or at any time) is the average cost of all capacity required to meet the peak. However, there is pragmatic evidence that this view is wrong. The British Central Electricity Generating Board found that, when it charged average capacity costs at peak, its Area Boards found it economical to put in peaking capacity at a much lower capital cost. Recently, the same issue has arisen in North Carolina. Municipal systems are proposing to purchase combustion turbines to avoid per-kilowatt charges developed by "averaging in" the much higher costs of baseload plants. Clearly, average capacity costs are higher than the real cost of meeting the peak.

It is necessary to determine the time-differentiated marginal costs that increments in demand actually impose upon the system. This can best be accomplished by turning to the load duration curve and asking what increase in costs would result from an increment in demand at any time. In the short run, before capacity can be adjusted, the marginal cost is the cost of energy for the hours served plus the shortage cost for

the hours not served. In the long run, after capacity has been adjusted, the marginal cost is the cost of energy plus the cost of capacity at peak. In an optimal system, the long-run capacity costs equal the short-run capacity costs; in fact, the following are all equal on an annual basis:

1. The cost of the machine used to meet the peak;
2. the long-run marginal cost of system peak demand; and
3. the short-run marginal cost of system peak demand (shortage cost).

In any real system, there are likely to be temporary mismatches, if only because of the discontinuous nature of plant adjustment. After a new plant addition, the short-run capacity costs (probable shortage costs) will be lower than the long-run capacity costs (cost of a peaker). As demand grows, the probable shortage costs approach and exceed the cost of peaking plant, triggering more capacity additions. Rather than follow the short-run costs in their oscillations around an equilibrium level, for tariff-making purposes we can imagine a plant continuously adapted to demand in which the long-run marginal cost of capacity is also the appropriate short-run cost of curtailment.

The marginal cost of capacity will be the cost of that plant used to meet the load (at peak) having the shortest duration. In the case of utilities having a highly peaked

daily load characteristic, the marginal cost of capacity will generally be the cost of a peaking plant. There will, however, be situations in which even a utility having such a load characteristic would never use a peaking plant, even in long-run equilibrium. In such circumstances, it is said that the peaker is outside of the cost envelope. This case is exemplified by a company having the long-term capability of utilizing stored hydro energy (either impounded or pumped). Here we would find that the capital costs would be higher than the cost of a peaker and, conversely, running costs at the peak would be commensurately lower.

Utilities having less peaked daily load characteristics may also find the cost of a peaking unit to be outside of the cost envelope. This case is exemplified by a company in which no portion of the load duration curve is of short enough duration that the least total cost method of serving the load is to build and run peaking plants. In this case, the cost of the plant used to meet the peak of relatively long duration should be used as the marginal cost of capacity. Running costs at the peak will be lower than if a peaking unit were used. Also, the capacity cost will be charged over a larger number of hours since the relatively level load curve will probably cause many more hours to have a significant LOLP. A utility with a very high load factor may therefore show little variation in hourly responsibility for capacity-related costs.

The marginal cost of generating capacity must be adjusted upwards to account for the reserve margin required

to meet the planning criterion. The pertinent reserve margin is not that which may pertain during some period of over- or undercapacity, but rather that reserve margin that would be required were load and capacity perfectly matched. The purpose of this computation is to enable the ratemaker to relate the cost of a kilowatt taken at the point of consumption to the installed cost of capacity required to serve the load at an appropriate risk of shortage.

Problems arise with this approach only if there is a chronic imbalance in the system. In cases of persistent overcapacity, the marginal shortage costs associated with prices based on long-run marginal costs and the consumption levels resulting from such prices might be very small. In these circumstances, we might want to depart from long-run marginal cost pricing in favor of short-run marginal cost pricing so that the installed capacity can be utilized efficiently. In such cases, the resulting cost of additional demand will not be the cost of building new peaking plant but the cost incurred by not retiring older, less efficient generating units. The components of this cost would be the manning and maintenance expenses, insurance, real estate taxes and foregone salvage value. This "overcapacity"¹⁴ should only be kept in service if such costs are less than the probable shortage costs that would result from retiring the unit.

¹⁴ Such capacity may also exist on another system, in which case its cost will be determined by the marketplace or by regulatory fiat.

Again, the marginal cost of generating capacity must be adjusted upwards to account for the reserve margin required to meet the planning criterion. The procedure in cases of chronic overcapacity would be to reduce the rate below long-run marginal cost so as to satisfy two criteria. First, the rate should not be reduced below the marginal running costs (energy plus other operating costs, including the cost of not retiring the plant); and, second, the rate should be reduced until enough additional consumption is encouraged so as to eliminate the excess capacity situation. If there is rather substantial excess capacity and if the relevant demand elasticities are small, this approach may simply yield the result that the short-run marginal cost is equal to the marginal running costs only.

Such an approach should be taken only with great caution. Since we expect that, over time, excess capacity will be eliminated, short-run marginal costs will necessarily rise toward long-run marginal cost over time. This means that prices based on short-run marginal cost will also rise as the excess capacity is eliminated. If such an approach is to be taken, consumers must be informed that current prices are not good predictors of future prices. In fact, they should be informed that it is expected that prices will rise over time as the excess capacity is eliminated. This will enable consumers to make long-run appliance decisions intelligently. These factors make a short-run marginal cost approach difficult to administer both in terms of expression (because of their changing nature)

where we have capacity imbalances, and in terms of providing consumers with good long-term signals for making long-term appliance choices. Except under extreme conditions of excess capacity or shortages of capacity, we would therefore recommend that prices be geared to the long-run marginal cost of capacity.

There are two other kinds of imbalance that will affect the marginal generating capacity cost. These kinds of imbalance do not necessarily involve overcapacity. In the case of the Eastern utilities which were plunged into non-optimality by the sudden increase in oil prices, it is the mix of facilities that is out of balance. As nuclear baseload plants come on line, relatively new and relatively high-efficiency oil plants will be pushed up the load duration curve. On systems having relatively high load factors, such machines might be used in cyclic fashion (i.e., they might be run for a week or for a month at a time) to meet peaks. In this case, the marginal cost of capacity could be the cost of not retiring such units as have been described above.

The other kind of imbalance can be found in the northwestern part of the United States where there apparently is sufficient hydraulic peaking capacity but an insufficient amount of water to meet total annual energy requirements. In this instance, it is possible that the marginal cost of capacity (i.e., the addition of a waterwheel generator at an existing dam site) will be less than that of a combustion turbine.

B. Marginal Energy Costs

In this section, we will, first (at the risk of being repetitious), briefly examine the relationship between the planning process and the way in which the system actually expands in order to set the stage for the determination of marginal energy costs; second, define the costs we seek; third, discuss the various data generally available; and, finally, present a sample computation.

The planner tries to meet forecasted peak and energy requirements by means of the least cost combination of existing equipment plus future additions of equipment representing current best technology at currently known costs. As a result, the aggregate mix of electric production equipment should asymptotically approach the optimal mix that would prevail if the system had no history. However, it seems clear that this will probably never be achieved at any single point in time--rather, the system configuration will oscillate about the desired mix because load grows in roughly a linear manner while capacity is added in lumps. If, for example, a group of peaking turbines is added, it will initially have more capacity than is immediately required. During the construction lead time required to build the next plant, these peaking turbines will run longer to meet the increasing load until such time as the next plant comes on line. At that time, turbine running hours will be drastically reduced. Over a span of five to 10 years (the

planning horizon), each type of machine tends to run the optimal number of hours that would be derived from the simplified model developed in Topic 1.3 (see footnote 13) given the costs peculiar to a given system. The degree to which this situation will not prevail depends on such things as operating constraints and the degree to which estimates of future costs are accurate. The foregoing suggests that marginal energy costs must be viewed over a period of time rather than at a particular point in time.

The tumult caused by the abrupt threefold oil price increase of 1973 threw many systems on the East coast, which had relied on imported oil, into a nonoptimal situation with respect to fuel. This situation will persist over the life of existing generation facilities. In such a case, the price signal given by marginal energy prices should reflect the fact that these systems will remain in a nonoptimal state for quite a while and should be based on the expensive oil that these utilities will be burning to serve load. To signal that nuclear energy is marginal (when this will not be true in some cases for possibly as long as 20 years) would be to invite the consumption of an expensive and scarce resource at a reduced price. The same principle may apply in other areas of the country where environmental restrictions are dictating the use of expensive fuels.

Using the simplified model, we can see that for a typical thermal system, in equilibrium, the marginal generating cost

at any hour is given by the energy cost of the last machine on line at that hour, plus the share of the marginal capacity cost implied by the relative probability that load will exceed capacity during that hour. To determine the marginal energy cost (also called the marginal running cost) at any hour, we simply have to determine the fuel and variable operating costs of the last machine on line--generally, the machine with the highest running costs in operation at that hour. Many companies project these data for several years in advance as a part of the planning process. The concept is also familiar to utility dispatchers and is often referred to as the system "lambda." It is calculated as the cost of the next increment in load and is often the basis for economy interchange transactions. (There may be cases where our marginal energy cost departs from the way some utilities calculate system "lambda," a complication we will discuss after reviewing a straightforward example.)

1. Direct Calculation from Production Cost Modeling Program

The determination of the marginal running cost for a prospective period is based upon a modeling of the system's operation. These data are usually available in some form from a utility's production cost modeling program. Ideally, one would want to design a model that, for each hour of the year, would consider the expected load, available capacity (given planned maintenance and forced outage) and the uncertainties of the forecasts and would then compute the most likely cost of an additional

increment in load for the hour. In the absence of the ideal, we have developed a methodology that uses data generally available to estimate the hourly costs.

2. Estimation When Direct Calculation Is Not Feasible

The basic inputs to this computation are a monthly load duration curve and a monthly production cost modeling program that accounts for forced outage as well as planned maintenance. This program must also provide an estimate of the kilowatt-hours generated in the month by each unit or the expected number of hours each unit was on line in the month. If the program supplies the hours run in each month for all units, by assuming that the units are loaded economically and that more expensive units are taken off line as load decreases, it is possible to construct a marginal energy cost duration curve that is compatible with the load duration curve. If the program only supplies each unit's generation, it is possible to stack the generation under the area of the load duration curve, placing the least costly units at the bottom and determining for the various segments of the load duration curve what unit provided the last increment of demand. Once the marginal unit has been determined over the range of the load duration curve, a running cost is assigned to each unit. Ideally this will be the fuel cost per kilowatt-hour based upon the incremental heat rate at that stage of the unit's loading, but since data for this calculation are frequently

not available, we have in the past generally used a unit's average heat rate.

3. Operation and Maintenance Expenses

The energy-related portion of operation and maintenance expenses per kilowatt-hour should also be included in the running cost. Essentially, power production and maintenance expenses will be related to the existence of the plant and remain fixed, vary with the rate at which the plant is used in relation to designed maximum capability or vary with the total energy output of the plant. The first type of expense represents a carrying charge or cost of having the plant; the second represents a demand (capacity) charge (the result of a short-term pushing of the machine to the point where maintenance costs arise); and the third represents a cost which, like fuel, is relative to total energy consumption. This last component is what should be included in the marginal running cost. It can be estimated on a kilowatt-hour basis by an analysis of the FPC power production operation and maintenance accounts. For example, the maintenance of boiler plant will, in part, be caused by demand and in part caused by continued usage. Since each company has different plants and different methods of operation, the relative proportion of expenses to each category, on an account-by-account basis, must be determined by discussion with the operating personnel of individual companies.

4. Grouping and Correcting for Inflation and Trends

The data at this point may be actually or potentially hour-by-hour marginal cost data over a five- or ten-year period, but since the eventual rates will not vary hour by hour, the costs are immediately grouped into those periods which have been tentatively selected as pricing periods. This is done by weighting the marginal cost for each hour by the total hourly load and deriving a weighted average marginal energy cost for each pricing period. We are now in a position to see the pattern of time-related marginal costs over the planning period.

A review of these data over several years usually will reveal two tendencies: first, if inflation is expected by the planners, the expected costs will be rising. Since we are interested in the current costs, we first correct the data, using the general price level deflator used by the planners, to obtain a series of constant prices. These prices will, however, still reflect the planners' expectation of relative price level changes between the various fuels. When this is done a second pattern becomes evident. In a well-adjusted system, the costing period marginal running costs (in constant dollars) tend to rise and fall throughout the planning period because, as explained on page 42 of this section, capacity additions are made in discrete units, while growth in load is roughly linear.

It would be possible to make rates which followed the oscillations of these costs around the equilibrium level,

but there would be little point in doing so. In looking over a five- or 10-year period at the pattern of costs for each each time of use, we simply smooth these variations around the equilibrium level in order to make a tariff which reflects, for each daily or seasonal costing period, the central tendency of the marginal energy costs for those hours (in constant dollars).

We now turn to less well-adjusted systems such as those in the eastern part of the United States. After accounting for general inflation, we will most likely find a trend in marginal running costs, as opposed to the oscillating pattern described above. The reason is that relatively efficient oil-fired baseload plants will be pushed up the load duration curve by nuclear plants, resulting in the displacement of peaking units. This latter effect will come about because the stretch-out of construction lead times during the recent past caused some utilities to overinvest in peaking capacity.

C. Example of the Computation

Figure 3 shows the derivation of a cost duration curve for a typical utility for the month of July and the estimation of weighted average on-peak and off-peak marginal running costs. This procedure should be used to develop the weighted average peak and off-peak marginal running costs for each month. From the results of these computations, costing period weighted average marginal running costs should be computed. Table 2 shows the costing period marginal

running costs resulting from the computation. These costs are deflated to constant dollars and the resulting marginal running costs in constant dollars are averaged over the period to give the central tendency.

In the final section, where we "put it all together," it will be described how marginal energy costs are adjusted for administrative and general loading factors, discussed in Section VIII-B, and for losses, discussed in Section X. The order of magnitude of these adjustments to marginal energy costs is between 2 to 4 percent and between 10 to 30 percent, respectively.

D. Problems in Application

1. Hydro Systems

Our analysis of hydro costs has been outlined in Topic 1.3: for systems with both hydro and thermal plants, the marginal cost can be imputed by examining the planning and operation of the system. If hydro is being dispatched above a two-mill machine and below a three-mill machine, we essentially evaluate the hydro at between two and three mills. The precise value imputed depends on the number of hours the hydro is marginal. Since dispatch plans usually treat hydraulic energy in an aggregate fashion, it is necessary to impute an energy cost to hydraulic energy for each of the costing/pricing periods (previously selected) during which this energy is marginal.

For costing purposes, hydro can be divided into three basic types: run-of-river, pondage and pumped storage

(which will be discussed later). The first, run-of-river hydro, is power which the utility must either take or forego. It cannot be stored and maximal utilization is obtained by taking as much energy as possible. When run-of-river hydro is the marginal source of production, it should be costed at solely the variable operation and maintenance expense of additional production. Very rarely would this energy be marginal. For such to be the case, it would mean that the utility was spilling excess water and, as demand increased, it increased production at zero marginal cost by passing more water through the turbines.

The second type of hydro, pondage, is much more likely to be marginal. This is hydro energy that can be stored. The utility has a fixed basin and amount of water and, again, is limited by total energy but can decide when to take the energy. Maximization of this source is obtained by scheduling the take to displace as much high-priced fuel as possible.

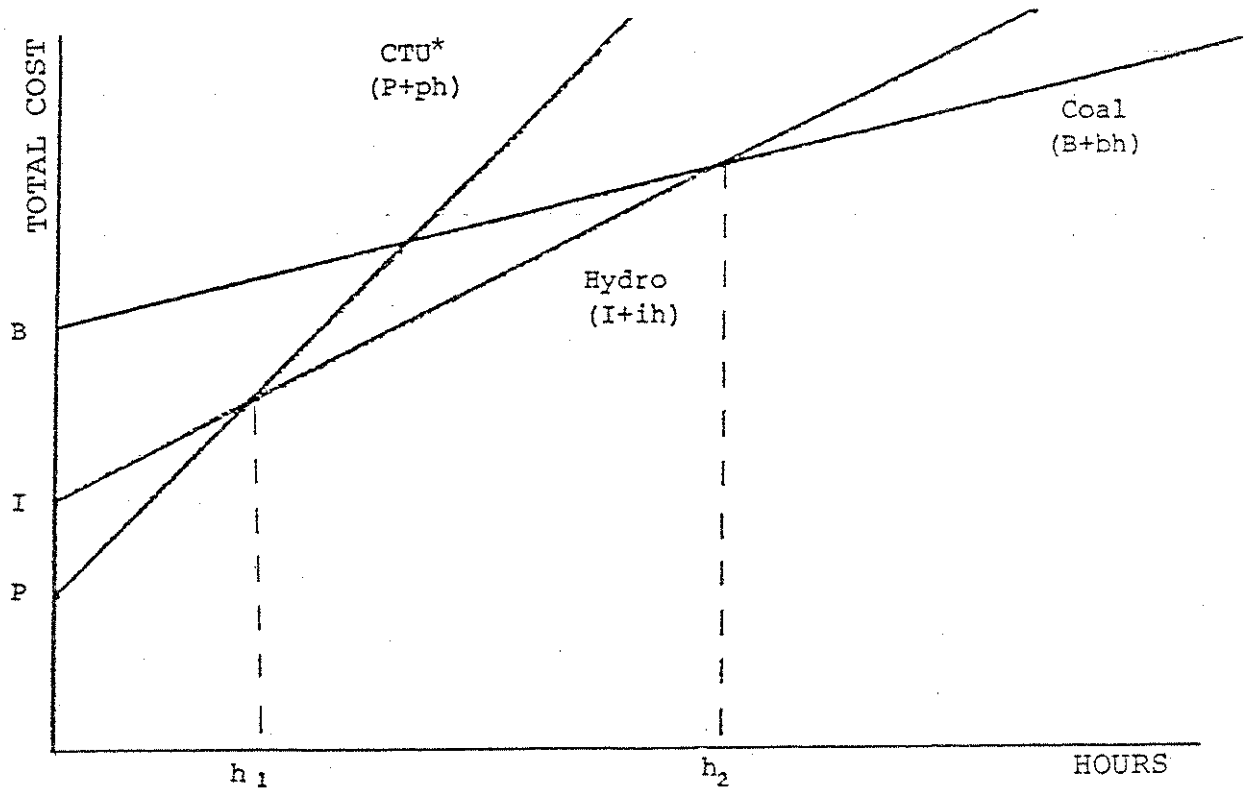
One of the more difficult tasks in evaluating hydro energy is simply determining which facilities are run-of-river and which are pondage. During freshet, when storage basins begin to overflow and water must be used or spilled, facilities that one would normally consider pondage are operated as run-of-river. The only accurate guide in evaluating hydro energy is the system operation. While views on the costing and pricing of hydro will differ from company to company, the basis

for dispatch will be the same--minimizing total cost by displacing expensive generation.

The basis for costing this energy then becomes the cost of the displaced energy. Depending upon the extent of the system's hydro operation, we may be able to analyze points along the load curve and determine what energy is being displaced. For example, if it is clear that hydro is used only to meet a portion of the load curve for which combustion turbines would otherwise be used, the marginal cost of that portion of the load curve for which hydro is marginal should be the cost of a combustion turbine. Similarly, whenever it is possible to accurately identify what energy is being displaced, hydro can readily be costed.

However, this is not always possible. If a company has a relatively large amount of hydro capacity, rather than attempting to identify the displaced energy, we can treat the hydro as a plant with its own cost characteristics lying somewhere below the running cost of a peaker and above the cost of an intermediate. In this case, we must impute a cost to the hydraulic energy. How can this be done? We must assume that, in principle, the aim is to schedule the water to displace as much high-priced fuel as possible, within the limits of the plant's own capacity and water supply. Using

the theories explained in the NERA simplified model of the generation system,¹⁵ we construct the diagram below.



Where:

P, p are capital and running costs of CTUs,
 B, b are capital and running costs of thermal coal,
 I, i are imputed capital and running costs of hydro and
 h_1, h_2 are minimum and maximum number of hours run
 by hydro.

¹⁵ A further discussion of the NERA model can be found in Topic 1.3 on pages 51 to 58. The model itself is presented in Attachment A of Topic 1.3.

* CTU: Combustion Turbine Unit.

The total cost curve for each type of machine starts at its annual fixed cost per kilowatt and rises over hours used by its variable cost per kilowatt-hour. The least total cost machine for a number of hours is the machine whose total cost curve is closest to the horizontal axis. In this case, B, b, P and p are known. By determining, or if necessary, estimating, h_1 and h_2 , we can solve for i, the imputed running cost for hydro. Based on this diagram and method, we will use hypothetical figures to demonstrate the calculation.

Assume that the running cost of coal plant is 11 mills per kilowatt-hour and the running cost of a CTU is 48 mills per kilowatt-hour. Assume an annualized capacity cost of \$32.25 per kilowatt for coal and \$16.45 per kilowatt for a CTU. Hypothesize that CTUs ran 100 hours and hydro operated 3,900 hours. Returning to the notation above:

$$\begin{aligned} B &= \$32.25 \\ P &= 16.45 \\ b &= 11 \text{ mills} \\ p &= 48 \\ h_1 &= 100 \text{ hours} \\ h_2 &= 3900 \end{aligned}$$

We see that $B-P = (h_2 - h_1)i - h_2b + h_1p$. Solving for i, the imputed running cost of hydro, we have:

$$\begin{aligned} 32.25 - 16.45 &= (3,800)i - 3,900(0.011) + 100(0.048) \\ 15.80 &= 3,800i - 42.9 + 4.8 \\ 53.90 &= 3,800i \\ 0.014 &= i. \end{aligned}$$

The running cost imputed to hydro is 14 mills. This method has the effect of costing all pondage hydro at one level and

is only suitable to systems where all pondage hydro is operated in a similar fashion. It blunts the time-differentiated cost to systems who operate hydro partly like a turbine and partly in the manner of an intermediate machine.

Pumped storage hydro is similar to pondage except that the actual cost of pumped storage is higher. The fuel cost of a pumped storage kilowatt-hour is the fuel cost of the thermal machine used for pumping adjusted for efficiency. Thus, to be economical, pumped storage energy must displace a machine with a higher cost than its own efficiency-adjusted cost. This is the trade-off upon which the decision to pump and release is based. Yet, once the pumping has been done, the aim is to use the potential energy in a way that displaces the highest priced fuel. The principle of costing pumped storage is, therefore, the same as costing pondage. It must be remembered, however, that pumped storage resources can usually be replenished regularly, whereas pondage will be subject to seasonal variation. This often will result in pumped storage being economic to displace lower cost energy than conventional pondage and having a lower imputed energy cost.

2. System Lambda and Marginal Running Costs

In systems which compute the dispatch cost for each hour of the planning period, a problem may arise in interpreting system lambda as the marginal running cost for the hour

because the dispatch engineer may have in mind not only the load at the hour in question, but also the build-up of the load expected over the day. An expensive machine may be brought on early (because its characteristics require it to be fully loaded) even though it is only needed for the peak load, and thereafter a cheaper machine may be used because of its greater flexibility to meet the increments in load as the peak is approached. In this case, the system lambda for a particular hour may be thought of as comprising not only the marginal costs for the hour in question, but also an anticipated cost for the later peak hours and, some adjustment may have to be made, particularly when the hours fall in different time periods. The question to be asked is, would a change in demand in any other hour affect the loading in the hour whose costs are being measured? If so, the system lambda does not measure only the marginal cost of the hour in question and must be adjusted.

Further complications in the assessment of marginal energy costs are caused by operating constraints. It must be kept in mind that the marginal energy cost at any hour is the cost that will be incurred by an increase in consumption, or saved by a decrease in consumption, at that hour. Although this will generally be the cost of the most expensive machine on line, there are three common cases where this is not true. First, many machines cannot be cycled over the course of a day. Therefore, a unit which is needed to provide capacity

during the peak hours may not be taken off line at night but is kept operating at a minimum loading. The loading on this machine will be neither decreased or increased in response to demand at other than peak times and, although it may be the most expensive unit on line, it is not the marginal machine. Second, for purposes of area protection and maintaining voltage throughout the system, utilities will run plants at key locations even though they are not the lowest cost source of energy. Third, combination steam-electric utilities will often run older plants to provide steam. Once again, these units will not respond to changes in demand for electricity and are not marginal units.

Undoubtedly, there will be companies in which other problem situations will arise. Intuitively, whenever marginal energy costs abruptly dip as the load increases or abruptly rise as the load decreases, the methodology in use to determine the marginal unit and the cost of that unit should be questioned.

3. Short-Run/Long-Run Considerations

When systems are far from optimality due to excess capacity or a nonoptimal plant mix, we might want to consider the use of short-run marginal energy costs.¹⁶ For example,

¹⁶ Similar considerations regarding computation, administration and consumer information arise here as in the discussion of excess capacity on page 40.

an oil-fired system which is adding nuclear plants in order to displace oil may develop a large excess of capacity which is entirely justified by the economics of the system (as when the total capital and operating expenses of the nuclear plant are lower than the fuel cost of the oil plant). In this case, marginal energy costs over the planning period should be falling towards its long-run level, while the short-run capacity cost is very low because of the excess capacity at the beginning of the period and rises towards its long-run level. Here it may be appropriate to have the rate reflect the fact that it is high-cost oil which is being consumed to produce energy rather than the long-run energy cost which signals the arrival of cheap energy (which may not take place for a long time).

We generally recommend computing the average of the marginal energy costs over the planning horizon. Exceptions to this general recommendation can be made in the light of particular circumstances.

VI. MARGINAL TRANSMISSION COSTS

In this section, we look at the investment in transmission facilities and at the operation and maintenance (O&M) expenses associated with these facilities. Once again, we will return to the planning process to show why some transmission investments should not be treated functionally as transmission, and to explain why transmission investment is a marginal cost and how it should be calculated. We will explain the theoretical underpinnings of the calculation, provide practical guides and a sample calculation, and discuss some problems of which the analyst must be aware.

A. The Nature of Transmission Investment

There are two categories of transmission investment (and associated O&M) that are more properly attributable to the generation function than to the transmission function. These are, first, those costs incurred to utilize sources of cheap energy available only at locations remote from load centers and, second, those costs associated with the establishment of power pool-related EHV grids which reduce individual utility generation reserve requirements.

In the first case, the decision to build these facilities was based on a trade-off between building a plant close to a load center (with no transmission) utilizing an expensive energy source and building a remote plant utilizing an inexpensive energy source plus the cost of transmission.

Using the concepts of the simplified model,¹⁷ the planner would formulate the following equation:

$$G_r + T + e_r h < G + eh$$

where:

G = Generator Investment
T = Transmission Investment
r = Remote
e = Energy Cost
h = Hours

which shows that it is less expensive to reach out for the cheaper source of energy.

In the second case, the individual members of the pool found that, by investing in an EHV grid, they could provide the desired level of reliability at a lower cost (through diversity) than would have been the case had each utility carried additional generating reserves. In both cases, these costs should be excluded from the analysis of transmission investment.¹⁸

The analysis of marginal transmission investment seeks to express the unit marginal cost in transmission facilities resulting from an increment or decrement in load. To this end, we ask, what are the causative factors of investment in transmission facilities? What system characteristics are

¹⁷ See Attachment A of Topic 1.3.

¹⁸ This does not mean that these costs have been ignored but rather that they are reflected in the cost of energy and the cost of reserves. For example, the fuel savings resulting from a remote generation site utilizing an inexpensive fuel is an offset to the capital cost of the plant and its associated transmission facilities.

responsible for an increase or decrease in the amount of transmission investment?

The chief aim of the transmission planner is to ensure that an adequate amount of power can be delivered to all points on the system at all times. To this end, the planner designs a system capable of serving the worst possible case, that is, transporting the peak load under outage (contingency) conditions.

Thus, the capacity of the transmission network is determined by the peak load on the system and the outage contingency employed in evaluating transmission system reliability. Assuming that the cost of reliability properly reflects a trade-off with the cost of outage and will remain constant relative to total transmission investment, the capacity of the transmission network will vary with the expected size of the peak demand. The proper marginal unit cost for transmission investment, therefore, is a cost per kilowatt of system peak demand. Such a cost, when translated into a rate, will give the consumer the proper price signal as to the cost effect of his probable contribution to system peak on investment in transmission facilities.

High voltage transmission facilities consist of large, expensive components. A utility does not build transmission facilities to a specified peak level and then add small additions as load grows to enlarge the system's capability. Instead, the planner, working from a set of forecast peak

loads, designs the system that will, over time, yield the least total cost. The planner accomplishes this by choosing the number of corridors, the size of corridors and the transmission voltage level that most economically transport the loads he expects to face. As voltage levels increase, the cost of corridors, towers and conductors all rise. With certain load densities, economies of scale may result from higher voltage transmission. The per-kilowatt marginal cost of transmission investment is, therefore, not necessarily a linear function. We can see from the foregoing that transmission investment tends to be lumpy. In order to treat these lumpy additions as though they were more flexible and could be had in very small increments (see footnote 1 on page 14), it is necessary to look at them over time in order to develop the marginal unit cost of capacity. The unit marginal cost we seek may be thought of as the unit cost of putting in place--all at once--the transmission capacity necessary to serve the aggregate system peak. Thus, in what follows, we are not attempting to cost growth.

B. Calculating Marginal Transmission Investment

As the nature of transmission investment is such that it can be causally related to peak demand, one would be inclined to calculate unit marginal transmission investment by simply dividing incremental additions to transmission plant by incremental additions to peak load. Unfortunately, there are many factors that prohibit blindly applying such a

calculation. Transmission investment is, first of all, of an uneven nature. Major projects may take several years to complete. To a large extent, transmission capacity is built not only to serve existing demand but also demands expected several years into the future. The simplified approach described above, therefore, does not necessarily yield the correct level of long-run marginal investment in transmission facilities.

To avoid some of these problems, we have several basic ground rules that we use in developing unit costs for transmission investment. The first is to investigate a time period of sufficient length such that lumpiness of investment or temporary aberrations in peak-load growth will not distort the result. A second consideration is that the chosen period consist of both an historical period and a future period. An analysis of the historical period would allow us to see what actually has happened, while an analysis of a future period would allow us to see not only the effects of a given peak-load forecast on future plans, but the effects of historical additions as well.

The third ground rule is to unitize additional investment on the basis upon which that investment was planned. This third rule may seem confusing after we have previously stated that transmission planning is done on the basis of peak demand. The point is that, over a particular time period, considerations other than additions to system peak may have

been the basis upon which incremental transmission investment was planned. For example, in a system that is building up or or running down the reserve margin, the capacity added to the transmission network at any specific time may not be related to peak additions. In such a case, the additions to transmission capacity may more properly be related to additions to generation capacity. Only in the long run, when the incremental reserve margin approaches the desired system reserve margin, will additions to peak load properly reflect the planned increase in the capacity of the transmission network.

After having chosen the proper time period, the analyst must convert all expenditures to a constant dollar base. Historic expenditures can be adjusted to constant dollars using a widely accepted index such as the Handy-Whitman index, or preferably, if data are available, an index based upon the experience of the particular utility. Future expenditures can be converted to constant dollars by removing the escalation that the planner has factored into his estimate. All capitalized costs (particularly interest during construction) should be included in both historic and projected data.

Next, the analyst must refer to our third ground rule. Having calculated the constant dollar investment in transmission over an appropriate span, should he determine a unit cost based on system peak additions or generating capacity additions? If the incremental reserve margin over the period

is roughly equivalent to the long-run desired reserve margin, he should, as the ground rule suggests, unitize on the basis of system peak additions. If the incremental reserve margin is not in line with the long-run desired reserve margin, generating capacity additions are probably a better guide to the level of marginal transmission investment.

Table 3 illustrates the calculation of marginal transmission investment. Note that all costs are expressed in 1975 dollars. A period of five historic and eight projected years has been analyzed. A unit cost is developed on the basis of additions to system peak demand because in this analysis the incremental reserve margin does not differ from the long-run reserve, and a discussion with system planners supported our feeling that incremental transmission planning was being predicated upon system peak demand additions. The costs for the two periods are similar, and the long-run level that we choose is the cost over all 13 years. Remember, if the unit cost had been developed on the basis of generating capacity, it would have been necessary to adjust for the long-run planned reserve margin. While this may seem confusing, it must be kept in mind that the capacity costs offered to the ratemaker should be expressed in terms of costs per kilowatt of peak demand and the cost of reserve should be included.

An alternate approach is a straightforward engineering cost estimate,¹⁹ in constant dollars, of constructing (a) a mile of line at the various voltage levels, and (b) switching stations, including per-Kva costs of transformation between transmission voltages. These estimates are multiplied, respectively, by miles of line, number of switching stations, and Kva of transformer capacity; the results are summed and divided by the increase in demand on the system over a prospective or past period in order to arrive at the marginal cost per kilowatt on the transmission system. A similar computation can be devised with regard to operation and maintenance expenses. If it were true that a system was only adding load by extending its territory, this would be the preferred method to use. However, most systems are growing internally, which requires reinforcement of existing circuits and stations; a "physical units" approach is, therefore, difficult to apply unless adequate records or detailed plans are available. For this reason, we prefer the first method.

In the section on distribution costs, we will discuss analyzing marginal unit costs using statistical techniques. We have not yet encountered a situation in which the statistical method was suitable for the analysis of transmission costs. Whereas the distribution system can, so to speak, be had in small components and continually be reoptimized to accommodate

¹⁹ The estimate is based on a company's particular construction practices and cost circumstances. These costs are generally the basic components of budgeted expenditures.

changing demand patterns, the lumpy nature of transmission investment (see pages 61-62) seems not to lend itself to a time series regression analysis.

The marginal cost determined by our methodology represents the long-run level of the contribution to marginal cost of a kilowatt. It incorporates the long-range decisions of the planner and, given constant technology and a reasonable degree of accuracy in the load forecast, the marginal cost will be stable. At any given point in time, the cost of an additional kilowatt may not be equal to our marginal cost. For example, there will be a point where a specific rise in demand causes a utility to construct a line on a new right-of-way at an additional unit cost much greater than the long-run marginal cost. Conversely, there will be a point in time when load is added with no resultant need for new transmission facilities. Some would argue that the cost of this load comes to zero marginal cost. What must be remembered is that we seek to determine the marginal cost and not a short-term cost of growth. The marginal cost is related to the state of technology and the design standards of electric utilities. It cannot be determined just by analyzing expenditures over an arbitrary time period. This is particularly important in the case of transmission investment where expenditures are often unevenly timed and, thus, adherence to our three basic ground rules is essential.

C. Problems In Calculating Marginal Transmission Investment

While the methods described above work reasonably well for most utilities, there are some particular questions that are encountered often enough to merit consideration by the analyst.

Are there expenditures in the transmission budget not related to increments in demand? Such expenditures are projects necessitated by road widenings and other governmental actions. The analyst should look at the transmission budget with an eye toward eliminating all expenditures not related to incremental demand. This distinction is not always easy to make. For example, if a governmental body ruled that all transmission lines should be placed underground out of respect for the aesthetics of the community, the following rules would apply. The cost of new transmission facilities would be increased to reflect internalization of social costs that are properly included as marginal costs. Budgeted expenditures related to undergrounding existing facilities are in no way related to the marginal demand costs and are not properly included as a marginal cost with respect to demand--they are retrofitting costs. The analyst would be faced with the problem of segregating such expenditures.

Are there expenditures related to loads added outside of the period being considered? Even after the analyst has determined whether to use peak or capacity additions as his divisor, he must see if any expenditures are directly

related to loads outside of the period. If, for example, expenditures for construction of a line designed solely to serve a generating station that will not be in operation until several years past the end of the period under consideration are included in the budget they should be removed.

Are there budgeted costs associated with moving lines and replacing poles? The dollar expenditures for these purposes are obviously not related to changes in demand and, therefore, should not enter our analysis. However, the probability that such expenditures will be required should be taken into account by considering the dispersion of retirements about the expected life of an investment.

Finally, does the analyst properly understand the accounting system? Does the accounting system arbitrarily classify a transmission voltage as distribution? Are charges for pool dispatch collected in transmission operations accounts? Do they belong there? In traditional parlance, we must properly functionalize both investments and expenses before conducting a marginal cost analysis. An area in which we must be particularly careful is that concerning transmission agreements with other utilities. It may be that a company has designed its transmission facilities to accommodate another company's requirements as well as its own. Does the constructor of the line receive payments for capacity used? If so, it is the net cost of the line that is sought. Or it may be the case that two companies have an agreement to exchange

capacity in one line for that in another. In this case, the correct capacity must be found in order to unitize costs.

On Table 4, our original example is expanded in order to illustrate how some of the conceptual aspects discussed earlier, as well as some of the problems raised here, should be handled. On this table, we note that there is the utility-built transmission which relates solely to remote generating facilities. Such "coal-by-wire" expenditures are removed from total additions to transmission plant since their cost was a part of the trade-off between different energy sources. Similarly, there are minor expenditures for transmission stations related solely to interconnections mandated by pooling agreements. The benefit to the utility is a reduced reserve margin. These expenditures are also eliminated. Finally, we see expenditures related to construction of an exit from a nuclear station that will be in service three years after our projected period. These expenditures are also removed from our analysis. The net expenditures, shown in Column (5), are then divided by system peak demand to obtain the marginal transmission investment per kilowatt. If the analyst had not encountered these problems, the computation in Table 3 would have been sufficient.

D. Transmission O&M Expenses

Transmission O&M expenses are related to the amount of plant in existence. Therefore, the addition of plant to meet additional peak demands will give rise to additional

operation and maintenance expense in proportion to the amount of plant added. In this sense, transmission O&M expenses are truly marginal costs. An explanation of why and how they are developed follows.

The first step in the analysis of transmission operation and maintenance expenses is to analyze, on an account-by-account basis (e.g., FPC account), actual transmission expenses for the last five years and budgeted transmission expenses for the next five years. Any extraordinary or expected nonrecurring expenses should be adjusted to typical levels. Any dispatch expenses that are related to pool or interchange operations are energy-related expenses and should be removed from the analysis of capacity-related transmission O&M expenses. Such expenses should be analyzed to determine whether or not they are marginal costs. If they are, they should be included in the proper component of cost--most likely energy. Any expenses related to the maintenance of transmission lines built specifically to serve remote baseload generation are part of the trade-off of the generation planning process and should be excluded from this analysis. Any fixed costs, such as leased rentals or fixed payments to another utility for use of transmission facilities, actually are payments in lieu of capital and should be removed from the O&M expense analysis and treated as investment. The remaining transmission O&M expenses are demand-related and can be analyzed in this respect.

Basically, the analyst must remember that the same rationale underlies the treatment of both expenses and investment. To avoid repetition, we have granted only summary treatment to the discussion of expenses. On Table 5 we show a sample of this computation. For each year, the total expense figure, adjusted as described above, should be divided by system peak demand to arrive at a cost per-kilowatt expense. In some cases, company personnel will feel that it is better to arrive at a unit cost by using generation capacity instead of system peak demand as the divisor. In such cases, the unit expense must be adjusted to account for the planned reserve requirement. These unit costs should then be converted to constant dollars using an appropriate index. Once in constant dollars, the trend in these costs is examined and a level of costs is extrapolated to several years into the future. For purposes of stability in ratemaking, we feel that a single cost level, representing the midpoint of a longer period within which technology is relatively constant, is preferable to annual changes in rates to reflect the trend of expenses.

VII. MARGINAL DISTRIBUTION COSTS

In distribution, unlike generation, marginal costs may vary between consumers, depending on location, density, terrain and local codes. The analyst must determine whether there exists a sufficient difference in costs between consumers to justify the establishment of tariff distinctions based on considerations such as those mentioned above. Regulators have, in many states, addressed this problem and have set up rules as to what tariff distinctions should be made. The decision as to how finely to segregate costs between customers then rests on both the analyst's judgment and the regulatory environment.

In our analysis of distribution costs, we must take into account the planning of the system. The system is planned to provide access to electric utility service for each potential consumer irrespective of the load, and it also has to carry the load. This could lead to the conclusion that an equation for the total cost of the distribution system would take the following form:

$$\text{Total Cost} = a(\text{customers}) + b(\text{demand on distribution}) + c.$$

However, since the number of customers and the demand on the distribution system are themselves highly correlated, such an approach would probably yield statistically insignificant²⁰

²⁰ Due to the high correlation between customers and demand, this statistical approach would result in an inability to separately identify the marginal effects of each factor on distribution investment costs (i.e., the values of a and b).

results. Therefore, we must turn to a technique that separately analyzes customer-related and demand-related costs.

Investment in an electric distribution system is causally related to three factors: customers, demand and energy. The customer-related portion of the distribution system should be viewed as a system capable of connecting all consumers but providing voltage only and no power. The demand-related portion consists of the components necessary to accommodate the demands that consumers actually place upon the system. The energy-related component refers to the aspect of distribution planning whereby least total costs are achieved by placing in service distribution capacity greater than demand and thereby reducing energy losses. In this section, we will outline the quantification of the customer and demand components. Energy will be discussed in the section on marginal losses. We will also discuss the customer and demand costs separately, and we will provide both an overview of each type of cost and a description of the computations. We will discuss problems that might arise with these analyses and, finally, we will discuss distribution operation and maintenance expenses.

A. Marginal Customer-Related Costs--Investment

1. The Nature of the Costs

The customer-related portion of the distribution system can ideally be viewed as a system which would cover the entire territory, the facilities dependent upon the size of area served, the density of the customers, etc., but would provide voltage only and no power. Clearly, this investment

should be treated as a marginal cost for new consumers. In this section, we will explain how to quantify this cost and examine why this cost is marginal not only for new but also for existing customers.

The customer-related marginal distribution costs are those directly attributable to the addition of a customer, as well as those varying in proportion to the number of customers but not the level of demand. The number of meters and services will (with some exceptions) be equal to the number of premises served and might be thought of as "hook-up" costs. The number and cost of distribution line poles (for example) will probably vary with the number of customers but not with the level of demand on the system and, thus, are also customer costs.

From a practical viewpoint, it can be seen that, if customer costs are not considered marginal and charged to existing consumers, a point will come when old facilities have to be replaced if service is to continue. At this time, the utility will have to choose between replacing the facilities and discontinuing service. If we assume, however, a continuing obligation to serve, this latter possibility is not a realistic option. The cost of this replacement will then fall due in the year the replacement is required. Rather than charge this cost in that year, however, the utility capitalizes the investment and earns a reasonable rate of return on the investment over its useful life. From a marginal cost viewpoint, the choice becomes either to assess the

full customer cost when it is incurred by the utility or to recognize annual charges on the customer-related portion of the distribution system as a marginal cost. We feel that the latter option is preferable in that it comports with traditional practice and leads to rate stability.

In order to compute the customer-related cost, therefore, we seek the per-customer cost of covering an electric utility's entire service territory with a distribution system capable of serving a population of minimum demand customers. We do not seek only the cost of extending the system to accommodate new customers. The computation is described below.

2. Making the Computation

As we would define it, the minimum demand customer would have a maximum load of one-half kilowatt, representing such basic items as a refrigerator, lights and auxiliary electrical equipment on a gas- or oil-fueled home heating system. The design of the minimum demand system would account for the fact that there are certain standards that must be met without regard for demand. Examples of these standards would be minimum pole heights to meet highway clearance, minimum conductor size to avoid sagging, and a minimum transformer size to meet the economic considerations of ordering and maintaining inventories. The minimum system would not merely reflect replacing all components currently installed with the minimum size component currently in use, but it would be a

system that could serve all the utility's customers at the minimum demand level. It would reflect customer and load densities. For example, while all services would be minimum size services, some primary feeder lines may have to be larger than the minimum size conductor to accommodate the estimated coincident demands placed upon them by the minimum demand customers. In dense areas where a single transformer currently serves three or four customers, a single transformer would be capable of serving many more customers. Yet, in rural areas where a minimum size transformer currently exists to serve a single customer, that one customer would still need the transformer even if his load were reduced to the minimum demand level. Since all customers would be treated as minimum demand customers, the only possible difference in cost between connecting a residential customer and connecting a commercial customer would arise from differences in their location on the system and the length of the service needed to connect them to the system.

Since our ideal view of the customer-related costs calls for providing voltage but no power, we would subtract from the costs computed (as described above) the material costs associated with conductors and transformers. Our system would then consist of all the labor costs necessary to put together today's minimum system and all material costs except those of conductors and transformers²¹ which we conceive

²¹ In some cases, there may be other demand-related material costs.

of as being chiefly demand related. Some may argue that we have overestimated the cost of the minimum system, while others may argue that the cost of some minimum conductors must be included if voltage is to be provided. Our proposed method balances these two arguments and provides a framework for measurement based upon actual construction practices as opposed to the construction of a hypothetical system.

Having made these computations, we divide the total cost of the customer-related system (in today's dollars) by the total number of customers in order to obtain the marginal customer-related distribution investment per customer.

While our discussion has addressed itself exclusively to an overhead system, the principles are equally applicable to underground systems. Additionally, we recognize that marginal customer-related costs may vary within a single service territory due to such factors as undergrounding and population density. In such cases, more than one marginal customer-related cost must be computed.

Table 6 shows a sample of this computation. Each component of the customer-related system is included, and the quantity required for each is specified. The cost is expressed in constant dollars and must include both material and labor costs except as outlined above for transformers and conductors. It should be noted that these latter costs include only the cost of installation. The total cost of all components in Column (3) is calculated and then divided by total number of customers served in Column (4).

B. Marginal Demand-Related (Capacity) Costs--Investment

1. The Nature of the Costs

Demand-related distribution costs can be viewed as all costs above the cost of the customer-related system that are incurred by power demanded by consumers. These costs would include the cost of conductors, transformers, and even such expenditures as the guying of distribution poles, which, since larger guys are required for heavier conductors, will vary with demand.

In analyzing demand-related distribution investment, we must once again return to the planning process and examine the causative factors of such investment. At the level of the link to a consumer which serves him alone, the maximum kilowatt demand, whenever it occurs, theoretically determines the size²² of the facilities required. At the generator bus, however, it is the consumer's demand at the time of the system maximum load that is important. Between these extremes, the common distribution system is designed to serve the consumer on the basis of the degree of coincidence between his maximum demand and the maximum demands of others.

Therefore, what has to be measured is the additional cost of distribution facilities required when a kilowatt of

²² We say theoretically because, in practice, the size of a facility may be invariant over a large range of kilowatt demands. The reason is that the economics of purchasing and storing materials may dictate a standardization of sizes.

load is added by a consumer--taking into account the diversity of all consumers' demands. Diversity consists not only of a time variance but also of a geographic variance. Given two separate geographic areas, one peaking at 8:00 a.m., the other peaking at 8:00 p.m., the same generating equipment can serve each peak, but the same distribution equipment cannot. So, in principle, one would want to consider each area separately to determine if the costs of service are different. However, it is often not feasible to distinguish between areas in the final analysis. We shall return to this point later when we discuss problems that may arise in analyzing distribution investment.

What follows from the above is that distribution cost responsibility will vary not only with a customer's maximum demand or contribution to peak demand, but also with the whole gamut of his load characteristics. Ideally, one would want to analyze separately each level of the distribution system for which a different demand was considered to be the cost causative factor. One could then meter each customer's probable contribution to demand at each time and assess cost in the most equitable way. At this stage, however, such a complex system is not envisioned. What we seek to measure is a distribution cost per kilowatt of a single measurable demand. This necessitates grouping customers into classes having homogeneous load characteristics.

Since rates probably will continue to be made on a class basis for some time, cost computations should reflect class load characteristics.

2. Making the Computation

In principle, there are three approaches to the derivation of demand-related distribution costs: we may predict the kinds of equipment to be added to meet a load increment and compute the cost; we may use a statistical approach; or we can take the first differences in capacity-related investments and in peak demand, over a period of time, and divide the former by the latter to obtain our estimate of the marginal unit cost.

The first approach is recognizable as the straightforward engineering cost estimate to which we have referred in the section on transmission.²³ It suffers from the same infirmity, i.e., internal growth of the system is extremely difficult to measure in physical units. We are inclined, on pragmatic grounds, not to recommend its use.

The second approach (statistical analysis) is our preferred method. An example of this approach is shown on Table 7. This table shows total demand-related distribution investment for a utility (in 1975 dollars) and the demands on the distribution system for a period of 17 years. Also shown on this table is the equation derived from the data

²³ See page 66.

using the least-squares regression technique. (It is assumed that demand-related distribution investments are those accounts covering substations, all conductors and conduit and distribution line transformers.²⁴) Note that the equation does not go through the origin but rather has a positive intercept. This intercept may be interpreted as that portion of the costs in those accounts which does not vary with demand. Intuitively, one might say that it represents such things as the cost of mounting the lightning arrester and fused cut-out with a transformer--a task whose labor requirement is invariant with demand but which may vary with the number of customers. The coefficient of the independent variable (peak demand) is the dollar per-kilowatt marginal cost of distribution capacity.

As with all statistical analyses, the analyst must possess a degree of statistical proficiency and check that all statistical tests are met. In our example, we show the results of the t-test, the \bar{R}^2 , and the Durbin-Watson statistic. Statistical inference, of course, is not a purely objective exercise. We feel that the results of this regression are valid and accurate predictors within a range of tolerance that will not substantially alter any recommendations made based upon our inference of the marginal distribution cost. Theoretically, it is indisputable that investment in the distribution accounts

²⁴ It is assumed that the customer-related costs previously discussed have been subtracted out where appropriate and also that replacement costs have been removed.